4. Derivatives in the Electricity Industry

Introduction

For several years, market analysts predicted rapid growth in the use of electricity derivatives. The U.S. Power Marketing Association, for example, argued in 1998 that the electricity industry would eventually support more than a trillion dollars in futures contract trading.[46] In fact, electricity derivative markets grew rapidly into the first part of 2000; however, in the last quarter of 2000, the market for exchange-traded electricity futures and options virtually collapsed. By February 2002, the New York Mercantile Exchange (NYMEX) decided to delist all of its futures contracts due to lack of trading.[47] The Chicago Board of Trade (CBOT) and the Minneapolis Grain Exchange (MGE) also suspended trading in electricity futures.

Enron's collapse eliminated a major innovator and trader of electricity derivatives. It also highlighted the problems of credit risk and default risk. In recent months, market participants have become increasingly cautious and have begun using methods to reduce credit risk and default risk by forming alliances, by increasing reliance on more traditional utility suppliers and consumers with known physical assets, and by reducing the scope of their derivative products (e.g., moving toward shorter term forward contracts).

The exit of electricity traders such as Aquila and Dynegy from the over-the-counter (OTC) market suggests that it is contracting, but overall data on the size and nature of the OTC market for electricity derivative contracts do not exist. What has actually happened to the electricity derivatives market over the past few years may never be known.

The discussion in this chapter suggests that the failure of exchange-traded electricity derivatives and the apparent contraction of the OTC market seem to have resulted from problems in the underlying market for electricity itself. Until the market for the underlying commodity is working well, it is hard for a robust derivatives market to develop.

Barriers to the development of the electricity derivatives market are numerous:

- The physical supply system is still encumbered by a 50-year-old legacy of vertical integration.
- Electricity markets are subject to Federal and State regulations that are still evolving.
- As a commodity, electricity has many unique aspects, including instantaneous delivery, non-storability, an interactive delivery system, and extreme price volatility.
- The complexity of electricity spot markets is not conducive to common futures transactions.
- There are also substantial problems with price transparency, modeling of derivative instruments, effective arbitrage, credit risk, and default risk.

The Federal Energy Regulatory Commission (FERC) has recently taken two steps, discussed below, to encourage competition in wholesale electricity markets. If these initiatives are successful, they will go a long way toward making wholesale electricity markets more competitive.

Structural and Regulatory Constraints on Electricity Markets

Market Structure

Many of the current constraints on developing competitive electric power markets and supporting derivatives markets for managing risk stem directly from the historic evolution of the domestic power industry. The U.S. electricity market began in the 1880s as a collection of several hundred unregulated electricity suppliers. Following the stock market collapse of 1929, many of the supplier companies went into bankruptcy, prompting calls for reform.[48] Congress responded by enacting two key legislative acts: The Public Utilities Holding Company Act of 1935 (PUHCA) and the Federal Power Act (PUHCA, Title II). The regulatory structure created by

[46] S. Spiewak, "Power Marketing: Price Creation in Electricity Markets," *PMA OnLine Magazine* (March 1998), p. 8, web site www.retailenergy.com/spiewak/sstoc.htm.

[47] NYMEX Notice number 02-57, "Notice of Delisting of NYMEX Electricity Contracts," (February 14, 2002).

[48] J. Wengler, *Managing Energy Risk: A Non-Technical Guide to Markets and Trading* (Tulsa, OK: PennWell Publishing, 2001).

those laws defined the States' role as regulating local markets and the Federal role as one of regulating interstate wholesale markets and corporate structures.[49]

Until recently the States exercised their retail market authority by giving integrated utilities exclusive franchises to serve customers within prescribed geographic areas. The integrated utilities owned the generators, lines, and distribution facilities needed to supply their customers. State public utility commissions (PUCs) regulated the retail price or "tariff" for electricity, typically using a prudence standard to determine which costs were acceptable to pass on to consumers and what would be a "fair rate of return" on investments.

In general, the prudence standard allowed utilities to build enough capacity to serve local demand. This regulatory approach led to the development of a physical electric supply industry that was optimized for serving local markets on a monopoly basis but offered little financial incentive for connecting the tariff-based electric companies. Currently, there is very little surplus capacity for moving power within regions (wheeling),[50] and the Eastern, Western, and ERCOT (Texas) markets for electricity remain virtually disconnected (Figure 11).

Regulation

Electricity regulation has some similarities to natural gas regulation. The wholesale prices for electricity and interstate transmission services are regulated at the Federal level. Retail prices and intrastate transmission are regulated by dozens of State PUCs. This multi-tier arrangement gives rise to electricity market rules that vary by locality. Retail deregulation legislation is also evolving at different rates in different regions and States.

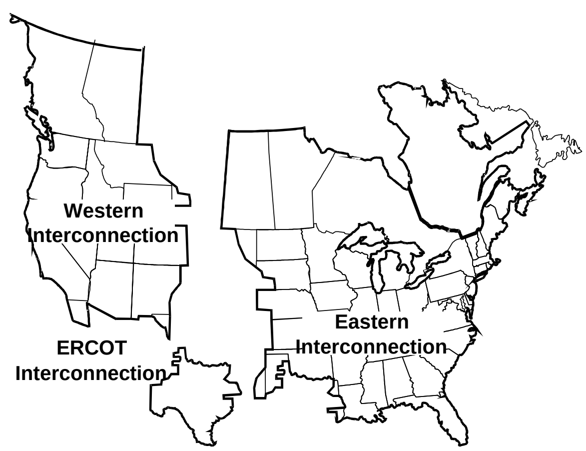
The Federal Energy Regulatory Commission (FERC) regulates wholesale markets and interstate transmission.[51] In 1996, the FERC took a major step in deregulating the wholesale electricity markets by ordering utilities to "unbundle" their generation, transmission, and distribution functions and provide nondiscriminatory access to the national electricity grid.[52] A new price discovery mechanism for transmission tariffs, the Open Access Same-time Information System (OASIS), was also created by FERC order.[53] These measures were intended to open the door for a robust wholesale electricity market in the United States.

Some States have also been actively promoting competition in retail markets. By the end of 1999, 24 States and the District of Columbia had enacted legislation to promote competition among retail electricity suppliers. Although deregulation activity initially proceeded rapidly, its progress has slowed in recent years, and the electricity industry is several years behind the natural gas industry in developing fully competitive markets.[54]

The physical design of electricity generation, transmission, and distribution systems has not kept pace with deregulation.[55] Consequently, many power plants still operate in a "must-run" mode, and the transmission system remains severely constrained by thermal limitations and congestion.[56] In short, for the foreseeable future, the various electricity markets may remain loosely connected with limited opportunities to move power from cheaper to higher cost areas.

Several States responded promptly to the FERC's initiative to deregulate wholesale electricity markets. California and Pennsylvania essentially led the market reform. In mid-2000 and 2001, however, California's electricity market virtually collapsed, causing a major utility to file for bankruptcy and another to accrue huge financial losses. The fallout from the California debacle served to

Figure 11. U.S. Electricity Interconnections



Source: Energy Information Administration.

[49]See Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update,* DOE / EIA –0562(96) (Washington, DC, December 1996).

[50]Wheeling occurs when a transmission-owning utility allows another utility or independent power producer to move (or wheel) power over its transmission lines.

[51]ERCOT is not under FERC jurisdiction, because its operations are largely isolated from those in other States.

[52]FERC Order 888, Final Rule, 18 CFR Part 35 and 385 (April 24, 1996).

[53]FERC Order 889, Final Rule, 18 CFR Part 37 (April 24, 1996).

[54]FERC Order 888 in 1996, requiring open access to electrical transmission services, roughly parallels FERC Order 436 in 1985, which required natural gas pipelines to provide open access to gas transportation services.

[55]P. Fusaro, *Energy Derivatives: Trading Emerging Markets* (New York, NY: Energy Publishing Enterprises, 2000).

[56]A "must run" power plant is one that must operate at all times during peak load conditions in order to satisfy the demand and reliability requirements of the grid for its particular location (i.e., there is no surplus capacity that could replace it).

remind everyone of the relevance of sovereign risk for electricity markets. In March and October 2001, for example, the FERC ordered California power wholesalers to refund tens of millions of dollars in overcharges.[57,58]

FERC is undertaking massive efforts to promote better integration of electricity markets across political boundaries. In 1999 FERC issued order 2000 requiring wholesale market participants to join regional transmission organizations (RTOs) to establish regional transmission management. Progress in establishing RTOs has been slow. In July 2002 FERC followed up with a Notice of Proposed Rulemaking to establish a Standard Market Design (SMD) that would apply within and across RTOs.[59] Within each RTO the business and operating rules would be the same for all market participants, and all the RTOs would be encouraged to adopt a standard market design, so that the basic rules and regulations of the regional markets would be similar from one RTO to another. If these efforts succeed, the result should be larger, more competitive regional markets and more cost-reducing trades across areas. Essentially the idea is to encourage a common market for electricity to replace the balkanized industry that exists today.

Risk Management Instruments in the Electricity Industry

As discussed below the FERC's RTO and SMD initiatives go a long way toward strengthening competition in U.S. electricity markets. Even with the development of robust competitive markets, however, the use of derivatives to manage electricity price risk will remain difficult, because the simple pricing models used to value derivatives in other energy industries do not work well in the electricity sector. These considerations suggest that innovative derivatives that are based on something other than the underlying energy spot price—such as weather derivatives, marketable emissions permits, and specialty insurance contracts—will be important for the foreseeable future. Forward contracts using increasingly standardized terms are also likely to supplant futures contracts for the foreseeable future.

Commonly Used Electricity Derivatives

Commonly used electricity derivatives traded in OTC markets include forward price contracts, swaps, options, and spark spreads. Several designs for electricity futures also appeared briefly on the NYMEX, CBOT, and MGE exchanges before being withdrawn.

Forward Price Contracts. The primary derivative used in electricity price risk management is the forward price contract. Similar to forward fuel contracts in design (see description in Chapter 2), electricity forwards typically consist of a custom-tailored supply contract between a buyer and seller, whereby the buyer is obligated to take power and the seller is obligated to supply a fixed amount of power at a predetermined price on a specified future date. Payment in full is due at the time of, or following, delivery. This differs from a futures contract, where contracts are marked to market daily, resulting in partial payment over the life of the contract.

Futures Contracts. Electricity futures contracts differ from forward contracts in that a highly standardized fixed price contract is established for the delivery or receipt of a certain quantity of power at some time in the future—usually, during peak hours for a period of a month. Also, futures contracts are traded exclusively on regulated exchanges. For example, the Mid-Columbia future offered by NYMEX specified a delivery of 432 megawatthours of firm electricity, delivered to the Palo Verde hub at a rate of 1 megawatt per hour, for 16 on-peak hours per day during the delivery month. To meet the long-term hedging needs of the customer (load-serving entity), power marketers typically combined several months of futures contracts into a "strip" of deliveries.

Electricity Price Swaps. Electricity swap contracts typically are established for a specified quantity of power that is referenced to the variable spot price at either the generator's or consumer's location. Basis swaps are also commonly used to lock in a fixed price at a location other than the delivery point of the futures contract. That is, the holder of an electricity basis swap has agreed to either pay or receive the difference between the specified contract price and the locational spot price at the time of the transaction.

Options Contracts. Many electricity customers prefer to have a delivery contract with flexible consumption terms. They prefer to pay the same rate per kilowatthour no matter how many kilowatthours they use. An electricity supplier who is holding a futures contract covering the delivery of a fixed number of kilowatthours is therefore at risk that the consumer could use more or less electricity than his futures contract covers. To cover the risk, a supplier often buys an electricity option (i.e., the right but not obligation to purchase additional power at a fixed price). *Spark spreads* (similar to *crack spreads* in the petroleum industry) are cross-commodity options designed to minimize differences between the

[57] See web site http://democrats.assembly.ca.gov/energy/pubs/EnergyUpdate23.pdf.

[58] *San Francisco Business Times* (October 8, 2001).

[59] See Federal Energy Regulatory Commission, "Commission Proposes New Foundation for Bulk Power Markets with Clear, Standardized Rules and Vigilant Oversight," News Release (July 31, 2002), Docket No. RM01-12-000 and Attachments (Questions and Answers), web site www.ferc.fed.us.

price of electricity sold by generators and the price of the fuels used to generate it.

Other Risk Management Tools

Although derivatives that focus on price risk *per se* have had mixed success in the electricity industry, three interesting tangential derivatives for managing risk in the industry are also being used: emissions trading, weather derivatives, and insurance contracts.

Emissions Trading. A critical input to electricity prices at fossil-fueled stations can arise from the requirement to meet various State and Federal air pollution standards. The Clean Air Act Amendments of 1990 established national ceilings on emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and set up a system of allotting marketable permits to power generators for each ton of emissions. At times, often depending on weather conditions, SO_2 and NO_x standards can require an electricity generator to reduce operations or pay more than normal for SO_2 and NO_x allowances. To hedge against potential losses, power plant owners can purchase or trade in SO_2 and NO_x allowances in order to manage their permit price risk and continue operations at more normal levels.

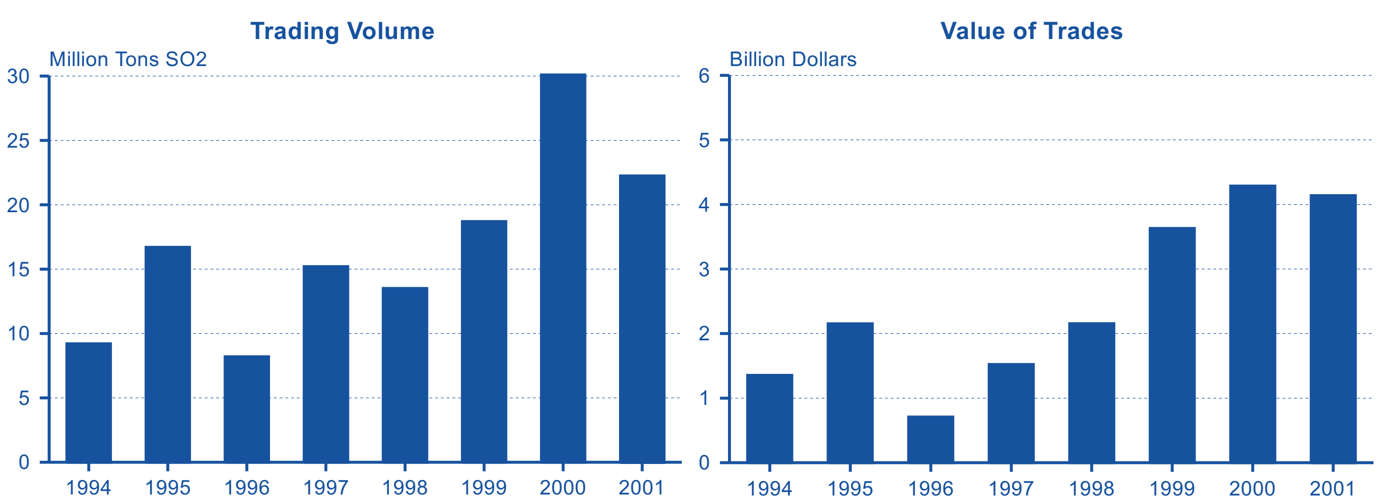
SO_2 trading has flourished in recent years. Trading volumes have increased from 9 million tons to more than 25 million tons over the past 8 years, with a notional annual value of transactions exceeding $4 billion in 2001 (Figure 12). Records compiled by the U.S. Environmental Protection Agency indicate that the notional value of private NO_x allowance transfers in 2001 exceeded $300 million, and a fivefold expansion of the NO_x program is expected during 2003 and 2004, when new Federal regulations expand NO_x allowance trading from the current 9 to 21 eastern States. In the SO_2 and NO_x markets, complex financial structures have been created to address the risk management needs of participants.[60]

Weather Hedges. Weather is a strong determinant of electricity prices and transmission availability. Weather risk is defined as the uncertainty in cash flow and earnings caused by weather volatility. For example, colder than normal summers reduce electric power sales for residential and commercial space cooling, leading to idle capacity—which raises the average cost of power production—and reducing demand for natural gas and coal. Similarly, lower than normal precipitation upstream of hydropower facilities can reduce power production and revenues.

To manage weather risk, some independent power producers have weather adjustments built into their fuel supply contracts. Other large energy companies and power marketers are now using "weather hedges" in the form of custom OTC contracts that settle on weather statistics. Weather derivatives include cooling and heating degree-day swaps and options.[61]

Insurance. Most participants in electricity markets use derivatives to manage the price risks associated with reasonably probable events, such as normal market fluctuations. There are also a number of less probable events that can affect their ability to supply electricity or take delivery and that pose large financial risks. In June 1998, for example, an investor-owned utility in Ohio

Figure 12. SO_2 Allowance Trading Activity, 1994-2001



Source: U.S. Environmental Protection Agency, webs sites www.epa.gov/airmarkets/trading/so2market/cumchart.html and www.epa.gov/airmarkets/trading/so2market/pricetbl.html. Values estimated by multiplying annual volume by average annual price.

[60] P. Zaborowsky, "The Evolution of the Environmental Markets," *Energy + Power Risk Management* (April 23, 2002).

[61] For further information on weather derivatives and risk, see web sites www.retailenergy.com/articles/weather.htm and http://ourworld.compuserve.com/homepages/JWeinstein/weatherd.htm.

experienced forced outages at its fossil fuel plant and at a nuclear power station. The utility's loss of supply occurred concurrently with a surge in electricity market prices, and it reportedly lost $50 million.

To cover the risk from such low-probability events, multiple-trigger derivatives and specialty insurance contracts are used to complement normal derivative products. For example, in a forced-outage derivative transaction, there are two triggers: (1) the utility must experience a forced outage, and (2) the spot price must exceed an agreed-upon strike price per megawatthour. If the two events occur together, the derivative contract will pay an amount specified in the contract. Insurance policies also offer possibilities of custom design and minimal counterparty credit risk.

Many of the current problems with electricity derivatives result from problems in the underlying market for electricity itself. Until competition in the market for the underlying commodity is working well, it is hard for a robust derivatives market to develop. In addition to the structural obstacles and regulatory uncertainties described above, deregulation of electricity markets and the development of truly competitive spot markets are hindered by the nature of electricity as a commodity, the extreme volatility of prices, the complexity of the existing spot markets, and a lack of price transparency.

The impediments to competitive markets dramatically complicate the forecasting of electricity prices and limit opportunities for arbitrage to resolve market imbalances. The added complexity also creates opportunities for price manipulation through market gaming and market power strategies.

The Unique Nature of Electricity as a Commodity

Storage and Real-Time Balance

The two most significant characteristics of electricity are that it cannot be easily stored and it flows at the speed of light. As a result, electricity must be produced at virtually the same instant that it is consumed, and electricity transactions must be balanced in real time on an instantaneous spot market. Electricity's real-time market contrasts sharply with the markets for other energy commodities, such as natural gas, oil, and coal, in which the underlying commodity can be stocked and dispensed over time to deal with peaks and troughs in supply and demand. Real-time balancing requirements also complicate the market settlement process. Some electricity market transactions occur before the system constraints are fully known or the price is calculated. In extreme cases, the settlement price may be readjusted up to several months later.

Electricity is typically "stored" in the form of spare generating capacity and fuel inventories at power stations. For existing plants, the "storage costs" are usually less than or equivalent to the costs of storing other energy fuels; however, the addition of new storage capacity (i.e., power stations) can be very capital intensive. The high cost of new capacity also means that there are disincentives to building spare power capacity. Instead, existing plants must be available to respond to the strong local, weather-related, and seasonal patterns of electricity demand. Over the course of a year or even a day, electricity demand cycles through peaks and valleys corresponding to changes in heating or air conditioning loads. Two distinct diurnal electricity markets also exist, corresponding to the on-peak and off-peak load periods. Each of these markets has its own volatility characteristics and associated price risks.

System Interactivity

The laws of nature, rather than the law of contracts, govern the power flows from electricity suppliers to consumers. By nature, electricity flows over the path of least resistance and will travel down whatever paths are made available to it. Because the suppliers and consumers of electricity are interconnected on the transmission grid, the voltage and current at any point are determined by the behavior of the system as a whole (i.e., impedance) rather than by the actions of any two individual market players. Consequently, the delivery of 100 megawatts of electricity differs dramatically from a simple fuel oil delivery in which 100 barrels of oil are physically piped or trucked between the oil supplier's depot and the consumer's facility.

The following example illustrates the system interactivity. Figure 13 shows interconnections among six hypothetical electric service systems. Supplier A makes a simple contract with B to deliver 100 megawatts of electricity. Once the contract is set, A turns on a generator to supply power, and B turns on electric equipment to create a new 100-megawatt load on the system. Because the loads on the power grid are interactive, the 100 megawatts of electrons will not flow directly from A to B. Instead, the new 100-megawatt supply and load cause a system-wide imbalance in impedance, and the electricity flows readjust across all the interconnected service areas. The contractual path for 100 megawatts of electricity from A to B does not match the actual physical movement of the commodity itself. This unique feature of electricity dramatically complicates transmission pricing by requiring a price settlement process that involves all market participants.

In this example, the power contract between A and B actually uses the physical systems and services of entities C, D, E, and F, which are not parties to the commodity contract. Thus, the virtual marketplace allows B to make transactions and manage price risk in a manner that would not be possible in other energy sectors. Suppose, for example, that party B wants to buy energy and party A prices energy significantly lower than either C or F. In Figure 13, party A cannot realistically transport the energy to B due to transmission congestion or other constraints. In other energy sectors, the inability to deliver the commodity would preclude party A from bidding at its low price. Either A would have to contract delivery services though the neighboring transmission systems, or B would be forced to buy energy at a higher price directly from C or F.

In the current virtual electricity market, party B can proceed to buy low-cost power from A despite the inability of A to make a direct physical delivery of the commodity. Because of system interactivity, the actual flows of the commodity must be determined in real-time. Thus, the basis risk and total price for delivered electricity remain unpredictable in both futures and forward derivative contracts until after the physical power transaction has occurred.

Price Volatility

As noted above, the high cost of idle capacity discourages deregulated electricity suppliers from acquiring surplus capacity that would rarely operate. When demand in an area exceeds the capacity of its low-cost suppliers, it is often difficult to import cheap power from other areas because of limited transmission capability. Demand then must be met by running cheaper generators to their limits and by dispatching more expensive generators. This gives rise to extreme price volatility, as described in Chapter 2.

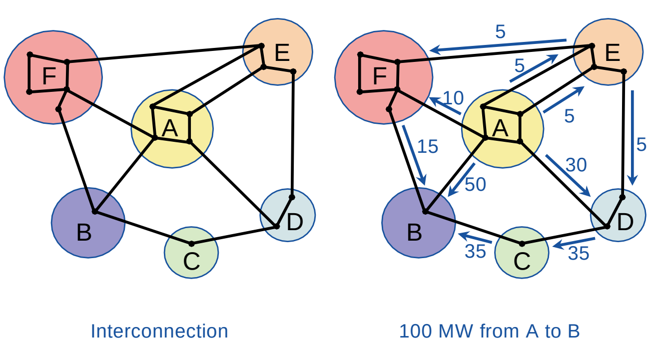
An efficient electricity system, with no transmission constraints, dispatches generators in order of their operating cost: the cheapest ones, generally baseline hydroelectric and nuclear generators, are generally dispatched first, followed by increasingly costly forms of generation, such as natural-gas-fired and oil-fired units. Over most system operating conditions, the supply costs are fairly flat; however, as the supply system gets closer to its capacity limit, the supply costs escalate rapidly. These conditions of supply produce a characteristic "hockey stick" shape in the supply cost curve (Figure 14).

Price volatility is exacerbated by the unresponsiveness (inelasticity) of consumer demand for electricity to high prices. Most consumers pay electricity prices that are still regulated, Because they are based on average generating costs, regulated prices do not vary significantly even when the real-time (marginal) cost of supplying electricity changes. As a result, there are few incentives in the U.S. electricity market to reduce demand.

Recognizing this problem, some European electricity markets already have adopted real-time pricing schemes. In France, for example, the electric utility transmits a special signal at various times of the day to indicate a change in the electricity price. Consumers can purchase sensor switches that detect the price change signal and regulate the operation of appliances such as hot water heaters and air conditioners. If they are successful in reducing demand at times of high supply cost and increasing it when cost is low, these measures should reduce price volatility.

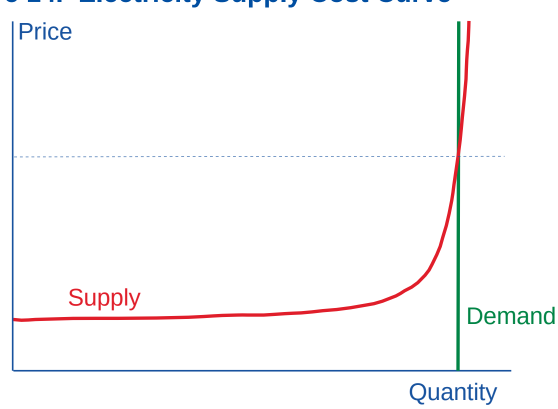
In the United States, one simple approach to reducing price volatility could involve making electricity prices more visible to large users.[62] Although large power users make up less than 1 percent of all electricity consumers, their share of power consumption is about 30 percent of total demand.

Figure 13. Delivery of 100 Megawatts of Electricity on Interconnected Systems



Source: Energy Information Administration.

Figure 14. Electricity Supply Cost Curve



Source: Energy Information Administration.

[62]See, for example, *Staff Report to the Federal Energy Regulatory Commission on the Cause of Wholesale Electricity Pricing Abnormalities in the Midwest During June 1998* (Washington, DC, September 22, 1998).

As it stands, the price volatility that characterizes electricity markets in the United States is unmatched in any other domestic energy market. On rare occasions, daily volatility can reach extremes of 1,000 percent or more. In 1998, for example, electricity prices in the Midwest spiked from an average of $25 per megawatt-hour to more than $7,500 per megawatthour for a short time in a single day in response to hot weather and forced outages.[63] Although volatility generally creates a high-risk market environment that is attractive to speculators, such extraordinary price spikes are difficult to manage. Given the extreme volatility of electricity prices, the cost of derivatives can be prohibitive.

Spot Market Complexity

Multiple Market Hubs

Historically, the Nation's power grid has been divided into numerous control areas where wholesale power is physically exchanged within regions of the North American Electric Reliability Council (NERC). Trading hubs are aggregations of representative electrical bus bars grouped by region, creating price signals and controls.

Theoretically, there are more than 166 potential hubs in the United States where electricity could be exchanged;[64] however, more than 85 percent of power trading historically has been conducted at only a dozen trading points. The Cinergy, Entergy, and TVA hubs have been the core of the market east of the Rockies, with ERCOT, PJM, ComED, NY-ISO, and New England constituting most of the remaining marketplace. In the West, most bilateral trading has been conducted at COB, Palo Verde, and Mid Columbia. Before the rollback of deregulation in the State, the California Power Exchange dominated the next-day market.

As a result of system interactivity, limited transmission capability between areas, and local congestion, there is only a weak relationship between pricing at the major hubs and pricing at nearby locations. In addition, it is not clear that the level of competition among traders is sufficient to ensure that arbitrage opportunities will be taken at minimum cost to ultimate buyers and sellers. Electronic trading, which appears to have great potential for encouraging beneficial trading, is still in its infancy, and the top 10 to 20 gas and power marketeers were responsible for the vast majority of activity in 2001.

Time-Differentiated Markets

The successful deregulation of natural gas markets influenced many initial policies on electricity deregulation; however, a single spot market design for electricity has proved to be elusive. Instead, differing regulatory views have led to the creation of several inconsistent market designs. For the majority of hubs, an independent system operator (ISO) and three-tiered market have failed to develop; rather, a combination of traditional tariff-based utility pricing, wholesale price matching, bilateral purchases, and sales contracts is used to commit, schedule, and dispatch power.

In contrast, in New England, New York, the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, and California, a three-tiered trading structure consisting of a "day-ahead" market, an "hour-ahead" market, and a "real-time" market was designed in order to ensure that market performance would match the grid's reliability requirements. The PJM Interconnection provides an illustration of how the day-ahead, hour-ahead, and real-time markets are coordinated.

The Day-Ahead Market. In the PJM region, market players submit their bids for generation and load to the day-ahead market. The bids and offers are binding in the sense that parties must perform, and accepted proposals are settled at the day-ahead prices. Any prearranged bilateral transactions may also be submitted. The bidding process continues until about 5AM on the day before dispatch, at which point a complex software program determines the "day-ahead" market-clearing prices. The software analyzes economics, overall system reliability, and each potential constraint in the transmission system. It then determines the optimal generation, the load schedules, and the market-clearing prices for each hour of the following day.[65]

The Hour-Ahead Market. On the actual day of delivery, a "balancing market evaluation" (BME) is performed about 90 minutes before each hour to take into account last-minute deviations from expected levels of electricity supply and demand. The BME considers any necessary additional bids and proposed transactions for that same hour. A modified schedule is then posted 30 minutes before the beginning of the hour.

The Real-Time Market. At the start of the hour for actual delivery, power is dispatched in a real-time market using a program called "security-constrained

[63]See Energy Information Administration, "Electric Utilities Pay Lowest Price for Petroleum Since 1976," web site www.eia.doe.gov/neic/press/press126.html (May 4, 1999); and R. Michaels and J. Ellig, "Electricity: Price Spikes by Design?" *Regulation*, Vol. 22, No. 2 (August 6, 1999).

[64]R. Braziel, "Trading Hubs: Where Power Is Traded and Why," *PMA Online Magazine* (December 1998).

[65]See web site www.eei.org/future/reliability/hirst_0104.pdf.

dispatch." It matches the generation forecast and actual data from the power system to the actual load demand during the hour. The results of dispatch are also used to compute real-time, location-based marginal prices for about 2,000 bus bars or nodes within the PJM service area.

Ancillary Services Markets

Most large hubs also have a market for the ancillary services that are required to ensure the smooth functioning and reliability of the electric power system.[66,67] Bids for ancillary services are placed in advance of the real-time market. Settlements are generally *ex post*. The ancillary services include energy imbalance services, spinning or non-spinning reserve capacity, supplemental reserve capacity, reactive power supply and voltage control services, and voltage regulation and frequency response services.

Transmission Services Markets

As described above, system interactivity creates a fundamental problem for electricity pricing, in that each party's decision to buy or sell electricity potentially affects other parties in economically important ways. In a sense, everyone on the grid is a partner in each electricity purchase or sale. The interaction creates the need for a market in transmission services.

Two different market designs are used for transmission services. The first approach assumes that it is more trouble than it is worth to charge each system user for the cost it imposes on the system. In this case, external costs are apportioned to users according to local rules and FERC-approved transmission tariffs. If congestion cannot be fully managed using re-dispatch, the transmission operators use a priority system to decide who remains on line. Transmission costs are "socialized" (shared out to everyone) in this approach.

The second approach (used by PJM) associates transmission charges with the costs each user imposes on the system. The transmission system controller calculates a "shadow price" of transmission on every congested line and then charges users according to their marginal contributions to congestion. When a line becomes overloaded, system controllers increase the implicit price of using the line until market participants voluntarily reduce the line loadings. A priority system for allocating transmission is not employed.

The advantage of the first approach is that the transmission pricing mechanism is simple. The chief disadvantage is that a priority system is used to decide who is dropped, and it does not account for the value of the trade. As a result, low-value trades can be allowed while high-value trades are curtailed. Who is dropped, when, and under what circumstances is not always clear. The advantages of the PJM approach are that all transmission users can see the economic impacts of their choices on all other users, and line capability is allocated to those who value it most. The chief disadvantage of the PJM approach is that the transmission price calculation is complex, *ex post*, and can lead to significant price variations, depending on the level of system congestion. To reduce the price risk to users, PJM also markets financial transmission rights (FTR) contracts, which allow users to lock in a transmission cost more than a day in advance.[68] The FTR is a financial derivative that compensates its owner for any transmission congestion charges that may be imposed during periods of constraint.

Most of the U.S. market currently "socializes" transmission costs. In that environment, arbitrage may not bring price convergence, because price-reducing trades cannot always be made. Efficient pricing of transmission services will remain a serious challenge to the development of competitive electricity markets.

Poor Price Transparency

Price information is a critical part of market mechanisms. Price information allows transactions between distant parties and gives market participants opportunities to anticipate future prices and to act on those anticipations by hedging. In ISO-controlled areas, the price for electrical energy itself is settled in the day-ahead, hour-ahead, and real-time markets. Although the reported prices are subject to revision and some prices (especially for ancillary services) are known only after the fact, the reported prices reflect the actual prices at which electricity is bought and sold. Most non-ISO markets, however, are not nearly as transparent.

Only about 10 of the largest hubs have large, liquid spot markets with readily transparent electricity price data, and only the IntercontinentalExchange web site shows megawatts traded. More than 100 hubs do not supply current market price data. Prices in one locality may

[66] A. Weisman, "FERC 101: The Essential Primer on the Fundamentals of FERC," *Energy Business Watch* (February 11, 2002).

[67] For the sake of brevity, a full discussion on ancillary services, reactive power, and black-start capability has been omitted. See, for example, A. Siddiqui et al. "Spot Pricing of Electricity and Ancillary Services in a Competitive California Market" in *IEEE Proceedings of the 34th Annual Hawaii International Conference on System Sciences* (2001).

[68] W. Hogan, "Getting the Prices Right in PJM: April 1998 Through March 1999, The First Anniversary of Full Locational Pricing," web sitewww.ksghome.harvard.edu/~.whogan.cbg.ksg/pjm0399.pdf (April 2, 1999).

depend on prices in other areas, adding to the overall complexity of price information in the marketplace. Certain transmission prices and ancillary charges are often not reported publicly and may not be known even to market participants until well after the market settles. Thus, although the price of the energy component may be published, the remaining components of total electricity price are not transparent. In addition, the majority of electricity derivatives are now exchanged in private OTC transactions that shield price information from other participants. These broad problems in price transparency make it difficult, if not impossible, to develop accurate models for pricing derivatives.

FERC's Standard Market Design

The FERC has recently taken two steps to encourage competitive wholesale electricity markets. On January 6, 2000, it published Order 2000, requiring ". . . all transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions [RTOs] in a timely manner."[69] The purpose of Order 2000 is to encourage trade and competition by ensuring open, equal access to the transmission grid within large areas.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) to ". . . establish a single non-discriminatory open access transmission tariff with a single transmission service . . . that is applicable to all users of the interstate transmission grid: wholesale and unbundled retail transmission customers, and bundled retail customers." The Standard Market Design (SMD) established under the proposal would apply to ". . . all public utilities that own, control or operate transmission facilities . . . ."[70]

Under the proposal, an Independent Transmission Provider would operate all affected transmission facilities. The Independent Transmission Provider would:

- Operate day-ahead and real-time markets for real power and ancillary services.
- Establish a two-part transmission charge: a fixed access charge paid by customers taking power off the grid and a congestion fee based on the differences in locational prices.
- Offer congestion revenue rights, which could be bought to "lock in" a fixed price for transmission.
- Establish market monitors to detect and mitigate market power.

Taken together the RTO Order and the SMD proposal address many of the fundamental problems with the electricity commodity markets discussed above, as summarized briefly in the table below.

Problem	RTO Order	SMD Proposal
Balkanized markets	A few regional markets	—
Lack of price, capacity, and other market data	Reported by RTO	Required
Varying business rules	General rules	Detailed rules
Binding day-ahead market	—	Required
Spot market	—	Required
Appropriate congestion charge?	—	Yes
Market power	—	Monitor

All these requirements flow directly from FERC's experience. Market monitoring, for example, came out of the California experience. It appears that California generators were holding back power from the California Power Exchange in 2000 in order to force heavier use of real-time markets and the California ISO reliability markets, resulting in higher prices. A new gaming strategy appeared in June 2000, suggesting that big utilities were deliberately under-scheduling demand requirements to force market-clearing prices down.[71]

FERC modeled its day-ahead and spot markets after PJM's markets, which seem to work well for at least two reasons. First, all day-ahead deals are binding: buyers and sellers settle at the termination of bidding. Generators that cannot perform in real time (because of outages, for example) have to pay for the power they do not deliver at spot market rates. Second, PJM manages congestion with locational prices. Had locational pricing been in place in California, Enron's various strategies for profiting from anomalies in prices would have failed.

In the "inc-ing load" strategy, a company artificially increases load on a schedule it submits to the ISO with a corresponding amount of generation. The company then dispatches the generation it has scheduled, which is in excess of its actual load, and the ISO is forced to pay the company for the excess generation. Under the SMD, the generator and the customer would have been paid the previous day at prices that equated overall supplies with demand. There would have been no systematic benefit from overscheduling generation and under-scheduling load.

Similarly, Enron's "Death Star" and "Load Shift" strategies worked only when congestion was not properly priced. "Death Star" involved the scheduling of energy counterflows but with no energy actually put onto or

[69] Federal Energy Regulatory Commission, Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000).

[70] Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 18 CFR Part 35, Docket No. RM01-212-000 (Washington, DC, July 31, 2002), p. 9.

[71] San Diego Gas & Electric Company, letter to the California ISO (June 23, 2000).

taken off the grid. This strategy allowed the company to receive congestion payments from the ISO without actually moving any energy or relieving any congestion.[72] The "Load Shift" strategy involved submission of artificial schedules in order to receive inter-zonal congestion payments. The appearance of congestion was created by deliberately overscheduling load in one zone and underscheduling load in another, connected zone, then shifting load from the "congested" zone to the "less congested" zone in order to earn payments for reducing congestion.

Neither Order 2000 nor the SMD NOPR requires that retail customers be exposed to changing wholesale prices. As discussed earlier, the extreme volatility of wholesale electricity prices is due to the rapid increase in marginal generation cost when generators operate near capacity, combined with the lack of customer demand response to wholesale price changes. Until customers, especially large ones, are exposed to real-time wholesale price variation, either wholesale electricity prices will remain volatile or the industry will have to maintain significant excess capacity. Nevertheless, the FERC initiatives, if successful, will go a long way toward creating well-functioning commodity markets. Once that is a reality, the prospects for electricity derivatives will be greatly improved.

Regulatory Challenges Ahead for Electricity Derivatives

The use (and misuse) of electricity derivatives raises at least three key regulatory concerns: What are the financial risks to ratepayers? How can market power and gaming be controlled? What is the proper role for demand-side management programs in the new market?

Financial Risk to Ratepayers. The financial risks resulting from the use of derivatives are illustrated by the number of companies that have suffered significant losses in derivative markets.[73] Large losses can be the result of well-intentioned hedging activities or of wanton speculation. In either case, regulators must be concerned with the impact that such losses could have on ratepayers who, absent protections, might be placed at financial risk for large losses.

Market Power. The preceding text has illustrated the complexity and non-homogeneity of the electricity markets. Amid this dynamic environment, opportunities abound for market power and gaming strategies to develop. Controlling this potential threat to competitive markets will require substantial regulatory review, as well as physical changes in the marketplace itself. In many areas of the country, only a small number of suppliers are capable of delivering power to consumers on a particular bus bar, and each of the suppliers can easily anticipate the bids of the others. In such "thin" markets, the price of electricity can be driven by market power rather than by the marginal costs of production. The need for overall market transparency will be critical to traders and to the market monitors established by the FERC's Standard Market Design.

Conservation and Demand. One of the key tools available to regulators for reducing the volatility of electricity prices is demand-side management programs. Electricity prices are most volatile during the on-peak hours of the day and substantially more stable (and lower) during the off-peak periods. This fact, coupled with the hockey stick shaped supply cost curve (Figure 14, above) suggests that substantial reductions in volatility could be achieved through the use of market mechanisms and demand-side management programs to shift consumption to off-peak hours. State and Federal authorities have been examining a variety of possible methods for shifting consumer demand for electricity; however, one of the most direct methods—real-time pricing for large electricity consumers—remains largely untapped.

[72] *Electricity Utility Week* (May 20, 2002), p. 2, and *Public Power Weekly* (May 13, 2002), p. 1.

[73] See, for example, Connecticut's investigation of the State trash authority's loss of $200 million in a failed deal with Enron: "Officials See Parallels Between Enron's Bank Deals and a Power Pact in Connecticut," *New York Times* (August 8, 2002), p. A21.